TRANSPOWER

TPM consultation: CNI proposed starting BBI customer allocations

Draft Record of application of the price-quantity method

Date: February 2026

Contents

1 Introduction

1. This **draft record** presents our application of the price-quantity method to calculate the Central North Island (**CNI**) benefit-based investment's (**BBI's**) proposed starting BBI customer allocations under the transmission pricing methodology (**TPM**).[1] The CNI BBI is one component of the NZGP1.1 major capex project.[2] We refer to the starting BBI customer allocations as the **starting allocations**.

2. We modelled the CNI BBI using the input assumptions from our application of the investment test to NZGP1.1, as set out in the NZGP1.1 major capex proposal (**NZGP1.1 proposal**),[3] except in relation to our assumption about the longevity of the Tiwai point aluminium smelter (**Tiwai**). These input assumptions are generally consistent with the input assumptions in chapter 2 of version 1.1 of the BBC assumptions book (**assumptions book**).[4] We have generally followed the processes in section 3.2 and 3.3 of chapter 3 of the assumptions book to calculate the CNI BBI's proposed starting allocations. Where we have used different input assumptions or processes than those in the assumptions book, we have stated them in this draft record.

3. We have applied version 1.1 of the assumptions book because that is the version that applied at the time of our original application of the price-quantity method to the CNI BBI in 2023, which we refer to as our **previous benefits modelling**. As noted above, the input assumptions in chapter 2 of version 1.1 of the assumptions book reflect the input assumptions we used in the application of the investment test to NZGP1.1. The changes to the analytical steps in chapter 3 of the assumptions book between version 1.1 and version 2.0 (the current version) of the assumptions book do not affect materially the application of the price-quantity method to the CNI BBI. All references in this draft record to paragraphs of the assumptions book are to paragraphs in version 1.1 of the assumptions book, unless stated otherwise.

4. We have defined some terms in this draft record for convenience. Please also reference the glossary in Appendix B.[5] Other terms used in this draft record have the meanings given to them in the TPM. All clause references are to clauses in the TPM, unless stated otherwise.

5. This draft record is structured as follows:
   - Sections 2-9 of this document step through the processes in sections 3.2 and 3.3 of the assumptions book as applied to this BBI.
   - Appendix A describes some of the modelling results from our wholesale market model (**SDDP**) to help stakeholders understand the proposed starting allocations.
   - Appendix B contains a glossary of terms used in this document.

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1 The TPM is in Part 12, Schedule 12.4 of the Electricity Industry Participation Code.

2 https://static.transpower.co.nz/public/uncontrolled_docs/NZGP1 MCP Application Addendum .pdf?VersionId=3GRsGmVQlFFjYv8tlUjyW7L4S5u9UAXaNet Zero Grid Pathways | Transpower.

3 NZGP1 submission | Transpower.

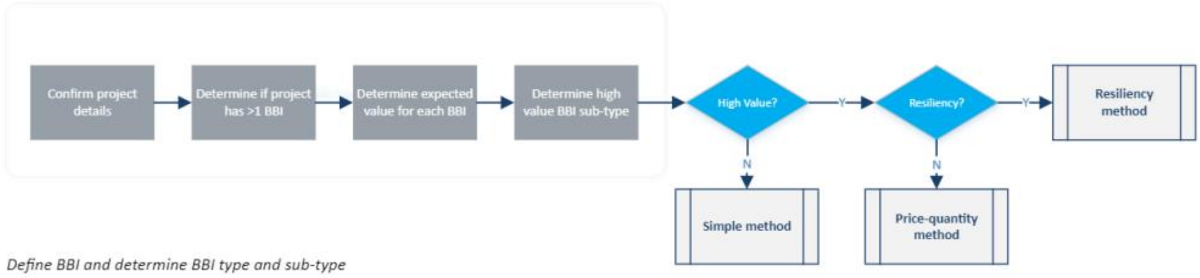
4 TPM Determination: BBC Assumptions Book v1.1, 16 March 2023.

5 The definitions in Appendix B are consistent with the assumptions book definitions.

2 Define BBI and determine BBI type and sub-type

6. This section describes our application of the stages set out in section 3.2 of the assumptions book to the CNI BBI (and as shown in Figure 1).

Figure 1: Define BBI and determine BBI type and sub-type



Define BBI and determine BBI type and sub-type

2.1 Confirm project details

7. The CNI 220 kV transmission system consists of the 220 kV Bunnythorpe–Whakamaru A and B lines and the 220 kV Bunnythorpe–Wairakei A line. These 220 kV circuits form part of the grid backbone. The lower North Island also has a 110 kV network, which is mainly supplied through the 220/110 kV interconnecting transformers at our Bunnythorpe substation. The direction of power flow through the region is determined by generation, direction of HVDC flow, and demand outside of the region. The CNI region is a main corridor for 220 kV transmission circuits through the North Island.

8. The CNI BBI will increase transfer capacity north from Bunnythorpe by 60-90% by:

- implementing variable line rating (**VLR**) and tactical thermal upgrade (**TTU**) of both 220 kV circuits on the Tokaanu-Whakamaru A and B lines to operate at a maximum temperature of 95°C,
- duplexing both the 220 kV circuits on the Tokaanu-Whakamaru A and B lines with Goat conductor to operate at a maximum temperature of 120°C,
- implementing VLR and TTU of both the 220 kV circuits on the Bunnythorpe-Tokaanu A and B lines to operate at a maximum temperature of 95°C,
- splitting the 110 kV circuit on the Bunnythorpe-Ongarue A line at Ongarue,
- upgrading protection on the 220 kV Huntly – Stratford 1 circuit on the Huntly-Taumaranui A line and Stratford-Taumaranui A line, between Huntly and Stratford, and
- replacing the special protection scheme at Tokaanu.

9. The application of the investment test to NZGP1.1 quantified changes in the cost of transmission losses, deficit (i.e. unsupplied demand), thermal operating costs, capital and fixed costs of generation, and emissions costs – all of which we consider to be market benefits as defined in the TPM. The application of the investment test to NZGP1.1 did not quantify any reliability, ancillary service, resiliency, or other benefits relating to the NZGP1.1 preferred options, including the CNI BBI (see sections 2.4, 5.1 and 6.1 of the NZGP1.1 proposal for more detail).

10. The fully commissioned asset value of the CNI BBI is expected to be $257m. There will be no transmission alternative opex associated with the CNI BBI.

11. We expect the CNI BBI to be commissioned after 23 July 2019 and it is not an exempt post-2019 investment. The CNI BBI is therefore a post-2019 BBI.

12. All of the principal benefits of the CNI BBI are expected to be released by the assets commissioned before the end of 2027. The CNI BBI's expected effective full commissioning date is 2027 (during FY 27/28).

2.2 Determine if project has >1 BBI

13. We applied the principles in paragraph 219 of the assumptions book to consider whether the CNI project should be combined with other investments in NZGP1.1 (the HVDC Reactive Support and the Wairakei projects). We consider the CNI project should be a separate BBI from both the HVDC Reactive Support and Wairakei projects because the projects:

- are in different electrical regions of the grid, i.e. the link between the North and South Islands (HVDC Reactive Support project) vs. the central North Island (CNI project) and the region north of Taupo (Wairakei project), and therefore are likely to have different beneficiaries;[6]
- have different periods in which the benefits accrue to beneficiaries – in addition to the CNI project's benefits resulting from relieving constraints, an important aspect of the CNI project's benefits results from it reducing transmission losses which occur whenever power is flowing through the CNI. The HVDC Reactive Support project only provides benefits when flow is approaching the existing capacity of the HVDC link; and
- have different expected commissioning dates.[7]

14. We have not included NZGP1's proposed reconductoring of the Brunswick-Stratford A line as part of the CNI BBI as that is a second stage of NZGP1 for which we have not yet sought approval from the Commerce Commission.

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6 For example, we expect generators in the Wairakei region will benefit from the Wairakei project but not the HVDC Reactive Support or CNI project.

7 The majority of the assets that make up the HVDC Reactive Support project and CNI project are expected to be commissioned by 2026 and 2027 respectivelyhttps://static.transpower.co.nz/public/uncontrolled_docs/NZGP1 MCP ATTACHMENT D - SCENARIO & MODELLING REPORT.pdf?VersionId=wt97ozdmYWIpNhdB4HSzMxrQR_KFRCfS. The majority of the assets that make up the Wairakei project were commissioned in 2025.

2.3 Determine expected value of each BBI

15. The fully commissioned asset value of the CNI BBI is expected to be $257m. There will be no transmission alternative opex associated with the CNI BBI.

16. As the sum of the BBI's fully commissioned asset value and transmission alternative opex is greater than the base capex threshold specified in the Capex IM,[8] the CNI BBI is a high-value post-2019 BBI. Therefore, Transpower is required to use one of the standard methods in the TPM (price-quantity or resiliency) to calculate its starting allocations.

2.4 Determine high-value BBI sub-type

17. There are no material resiliency risks being mitigated by the CNI BBI – its need is not primarily attributable to mitigating a risk of cascade failure or a high impact low probability (**HILP**) event. This is consistent with the application of the investment test, which did not quantify any resiliency benefits associated with the CNI BBI.

18. Therefore, the CNI BBI is not a resiliency BBI under the TPM and we are required to apply the price-quantity method to calculate its starting allocations (clause 43(2)).

2.5 Expenditure on existing BBIs

19. We are required to treat the CNI BBI as a separate post-2019 BBI because it:
    - is an enhancement investment commissioned after 23 July 2019 (clause 37(3)), and
    - is not an exempt post-2019 investment (it will be commissioned after 1 July 2021) (clause 37(5)).

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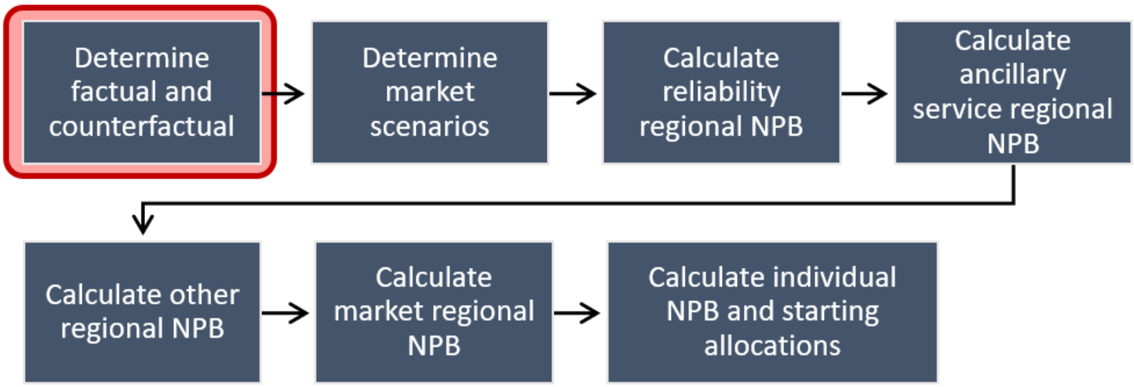
8 At the time of our previous benefits modelling, the base capex threshold was $20m. This has since increased to $30m. The fully commissioned asset value of the CNI BBI is above both thresholds. The latest version of the Capex IM is here: Transpower-Capital-Expenditure-Input-Methodology-IM-Review-2023-Amendment-Determination-13-December-2023.pdf.https://www.comcom.govt.nz/assets/pdf_file/0013/350500/Transpower-Capital-Expenditure-Input-Methodology-Determination-consolidated-as-of-29-January-2020.pdf

3 Determine factual and counterfactual

20. This section describes our application of the stages set out in section 3.3.1 of the assumptions book to the CNI BBI (and as shown in Figure 2).

Figure 2: Determine factual and counterfactual



3.1 Determine factual

21. The factual is the grid state after the CNI BBI has been fully commissioned.

3.2 Determine investment type and counterfactual

22. The CNI BBI does not constitute a refurbishment or replacement investment as defined in the TPM (which refers to the corresponding definitions in the Transpower Capex IM[9]). It is therefore an enhancement investment.

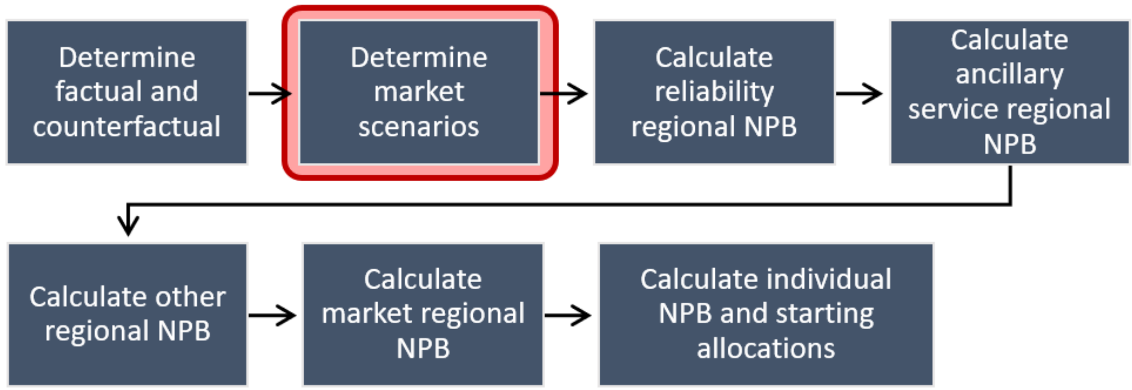
23. Consistent with clause 45(2)(a), the counterfactual is the current state of the grid in the CNI without the CNI BBI.

[9] https://www.comcom.govt.nz/assets/pdf_file/0013/350500/Transpower-Capital-Expenditure-Input-Methodology-Determination-consolidated-as-of-29-January-2020.pdf See Capex IM definitions of "asset refurbishment" and "asset replacement".

4 Determine market scenarios

24. This section describes our application of the stages set out in section 3.3.2 of the assumptions book to the CNI BBI (and as shown in Figure 3).

Figure 3: Determine market scenarios



4.1 Obtain market scenarios used in consultation

25. We have mostly used the market scenarios from the application of the investment test to NZGP1., as described in Attachment D of the NZGP1.1 proposal. Unless otherwise stated in section 4.2 of Attachment D of the NZGP1.1 proposal, these are consistent with the assumptions in version 1.1 of the assumptions book.[10] Section 8.3 presents the additional assumptions used that are not shown in either Attachment D of the NZGP1.1 proposal or the assumptions book.

26. A significant change from the application of the investment test to NZGP1.1 and our previous benefits modelling is our assumption around Tiwai, which was assumed to leave in either 2024 or 2034. We now assume that Tiwai remains throughout the standard method calculation period. We also developed new generation expansion plans to ensure there is enough generation in the system with the higher demand.

4.2 Obtain market scenarios from the assumptions book

27. Other than the assumption around Tiwai, we have not departed from the market scenarios or modelling inputs used in the application of the investment test to NZGP1.1 and our previous benefits modelling. We consider these will produce starting allocations that are broadly proportionate to EPNPB.

[10] In addition to the assumptions described in section 4.2 of Attachment D of the NZGP1.1 proposal, we also assume the Te Rapa generation plant closes in 2023, consistent with the application of the investment test to NZGP1.1. At the time of our previous benefits modelling, this assumption was based on Contact's June 2022 announcement. The Te Rapa generation plant closed in June 2023.

4.3 Determine if different market scenarios are required

28. Other than the assumption around Tiwai, we have not departed from the market scenarios or modelling inputs used in the application of the investment test. We consider these will produce starting allocations that are broadly proportionate to EPNPB.

4.4 Determine if sensitivities should be modelled

29. A sensitivity is a market scenario included in the modelling to specifically test (and include) the influence of one discrete change to our input assumptions occurring independently of other input assumptions.

30. In the application of the investment test to NZGP1.1 and our previous benefits modelling, Tiwai is assumed to close in December 2024, with a sensitivity of Tiwai closing in 2034 (as noted in section 1.5.1 of the NZGP1.1 proposal). We have not included this sensitivity in this application of the price-quantity method to the CNI BBI.

31. The NZGP1.1 proposal did not assess any other sensitivities relating to the market scenarios. On the basis that we do not consider any other sensitivities meet the assumptions book criteria at section 3.3.2.6 and for consistency with the assumptions used in the application of the investment test, we have not used any other sensitivities (consistent with clause 43(5)).

32. Therefore, there are five scenarios used in total – the five 2019 Electricity Demand and Generation Scenarios (**EDGS**) scenarios, each with Tiwai remaining throughout the standard method calculation period.[11]

4.5 Determine the weightings to be applied

33. As described in section 4.1.1 of the NZGP1.1 proposal, the application of the investment test gave equal weighting to the five 2019 EDGS scenarios. We have used the same weightings for this application of the price-quantity method to the CNI BBI.

4.6 Hydro, load, and generation expansion variations

34. The market scenarios are consistent with clause 46(1) because they include the following variations:

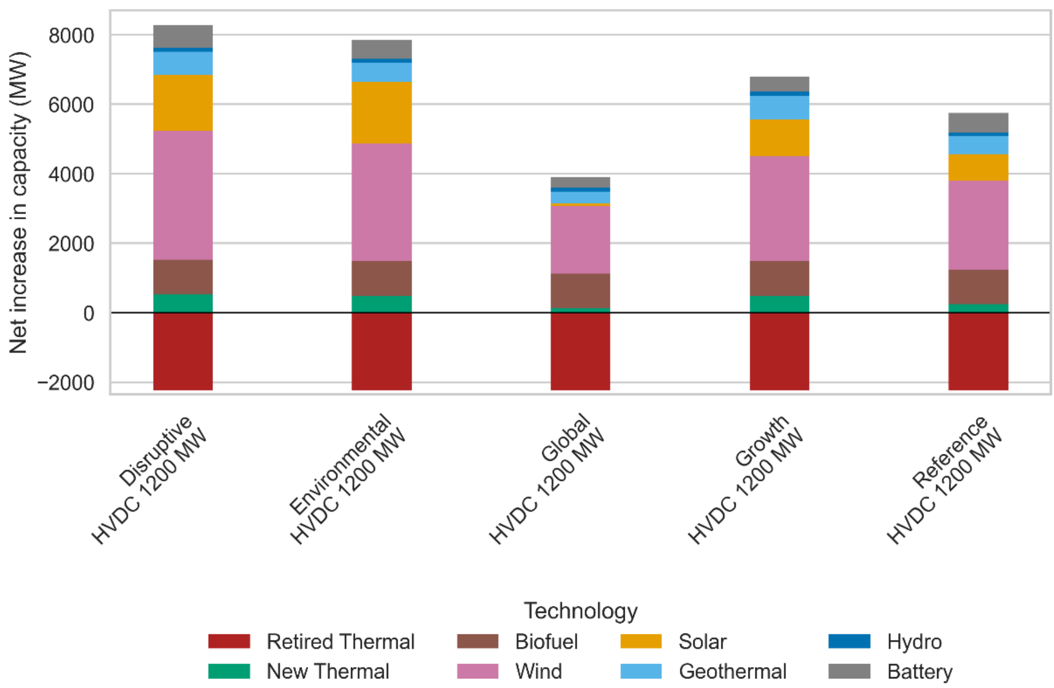
    - load growth across the scenarios (see section 2.3 of Attachment D of the NZGP1.1 proposal);

[11] Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz).

- hydrology, by using 50 synthetic hydro inflow sequences for each market scenario, representing the historical hydro inflow distribution (see section 4.2 of Attachment D of the NZGP1.1 proposal); and
- generation expansion, by using different generation expansion forecasts resulting from different demand forecasts and the generation cost declines specified in the assumptions book. Figure 4 and Figure 5 show the generation changes from 2022 to 2047 for each 2019 EDGS scenario. We used the same generation expansion plans in both the factual and counterfactual.[12] We expect the CNI BBI to materially influence generating plant investment decisions but we have exercised our discretion not to apply different generation expansion market scenarios in the factual and counterfactual as we do not think using the same generation expansion scenarios in the factual and counterfactual will materially impact the starting allocations for the CNI BBI:[13]
    - The standard method aims to identify each beneficiaries' benefit relative to other beneficiaries, rather than absolute benefits.
    - The CNI BBI uses the clause 51 method (see section 8.5), under which starting allocations are largely determined by the counterfactual modelling.

35. Additional modelling detail is provided in Appendix A.

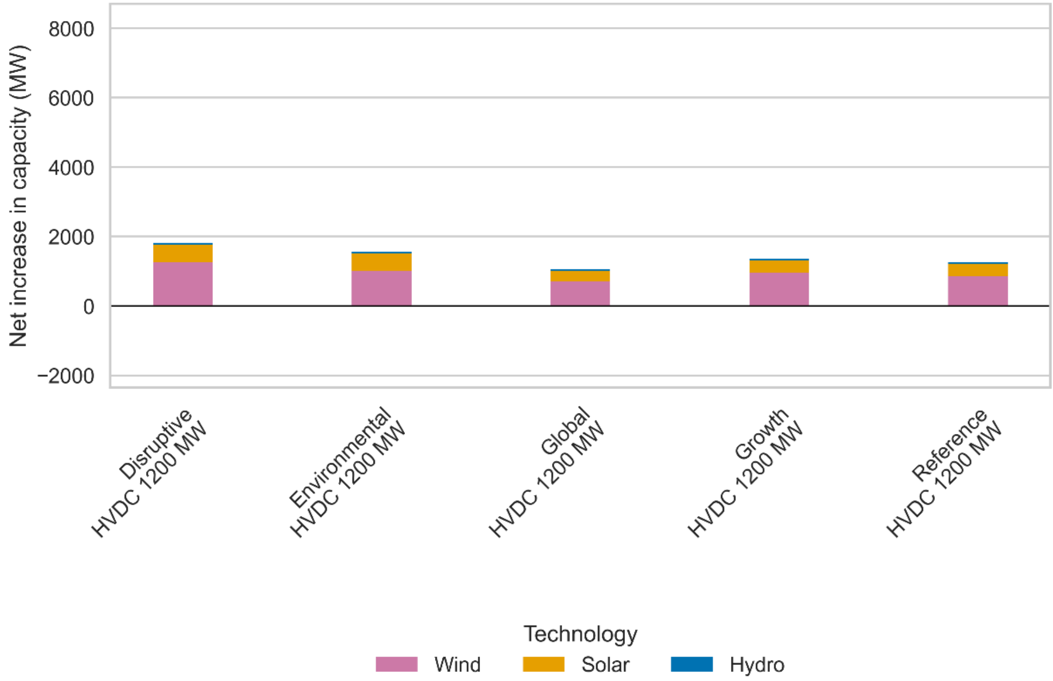
Figure 4: North Island generation changes from 2022 to 2047



12 These are the same expansion plans used in the HVDC Reactive Support factual case modelling, which upgrades the HVDC capacities in 2026 to 1200 MW northward flow capacity and 850 MW southward flow capacity.

13 Further, there was not an equivalent factual scenario available from the investment test, because the investment test modelled all projects together in a single analysis, whereas here we are assessing EPNPB of each BBI separately.

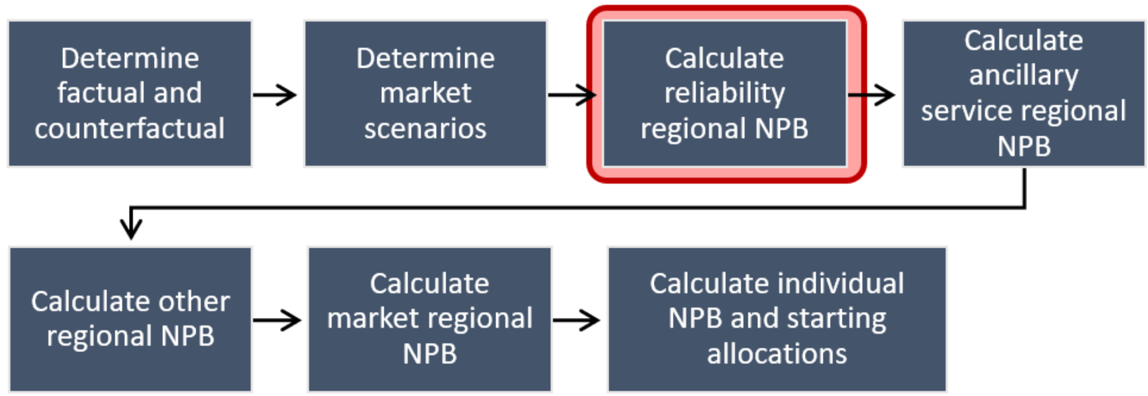
Figure 5: South Island generation changes from 2022 to 2047



5 Calculate reliability regional NPB

36. This section describes our application of the stages set out in section 3.3.3 of the assumptions book to the CNI BBI (and as shown in Figure 6).

Figure 6: Calculate reliability regional NPB



5.1 Determine if there are reliability benefits

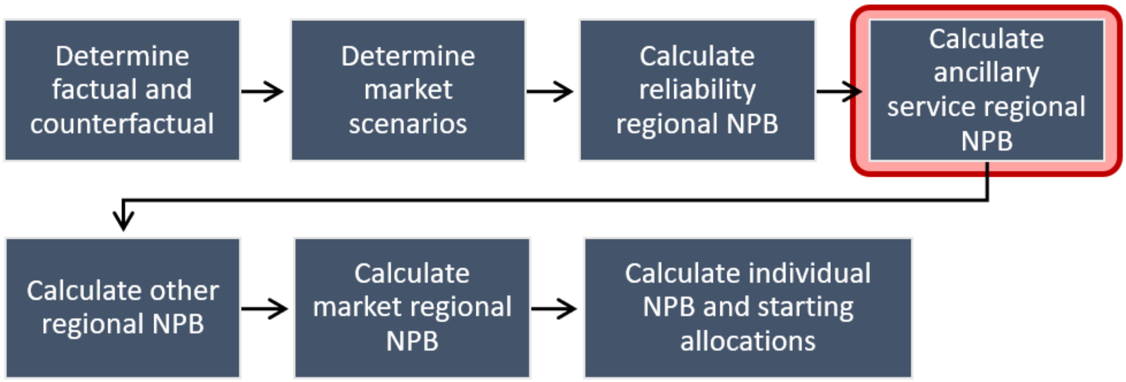
37. We do not expect the CNI BBI to have reliability benefits relative to the counterfactual because the investment does not increase the redundancy of supply to any grid points of connection (it adds no new lines or circuits).

38. Therefore, we do not consider the CNI BBI to be a reliability BBI and did not calculate reliability regional NPB under clause 54.

6 Calculate ancillary service regional NPB

39. This section describes our application of the stages set out in section 3.3.4 of the assumptions book to the CNI BBI (and as shown in Figure 7).

Figure 7: Calculate ancillary service regional NPB



6.1 Determine if there are ancillary service benefits

40. We do not expect the CNI BBI to materially reduce the cost allocated to our customers of any specified ancillary service (through changes in price or quantity) relative to the counterfactual. In general, we only expect a BBI to reduce the cost of ancillary services if it provides or enables ancillary services in the market (e.g. the HVDC's Frequency Keeping Control),[14] or if it enables another ancillary service provider to be dispatched e.g. a transmission project that enabled a grid-scale battery to connect to the grid and provide reserves. The CNI BBI does not provide ancillary services as it is an enhancement to the AC network, and we have no reason to think it materially enables ancillary service providers to be dispatched.

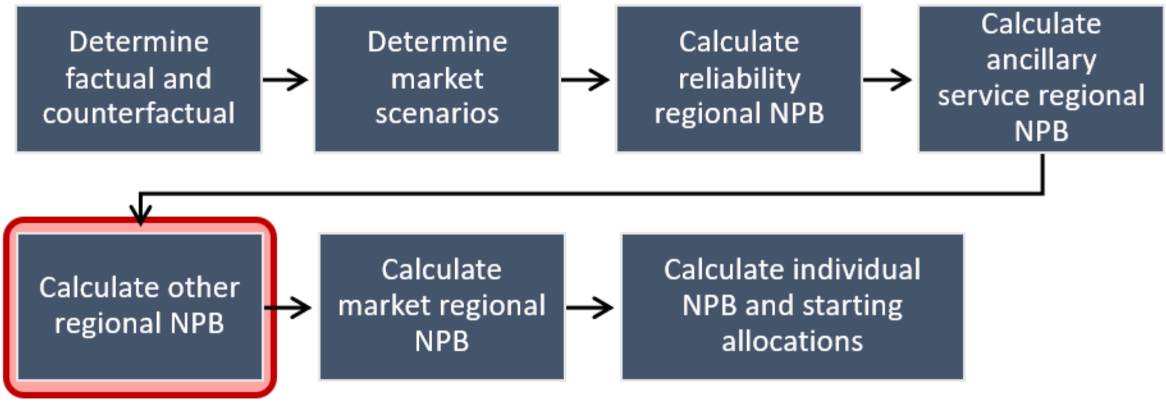
41. Therefore, we did not calculate ancillary service regional NPB under clause 53.

14 Frequency keeping control and round power information

7 Calculate other regional NPB

42. This section describes our application of the stages set out in section 3.3.5 of the assumptions book to the CNI BBI (and as shown in Figure 8).

Figure 8: Calculate other regional NPB



7.1 Determine if there are other benefits

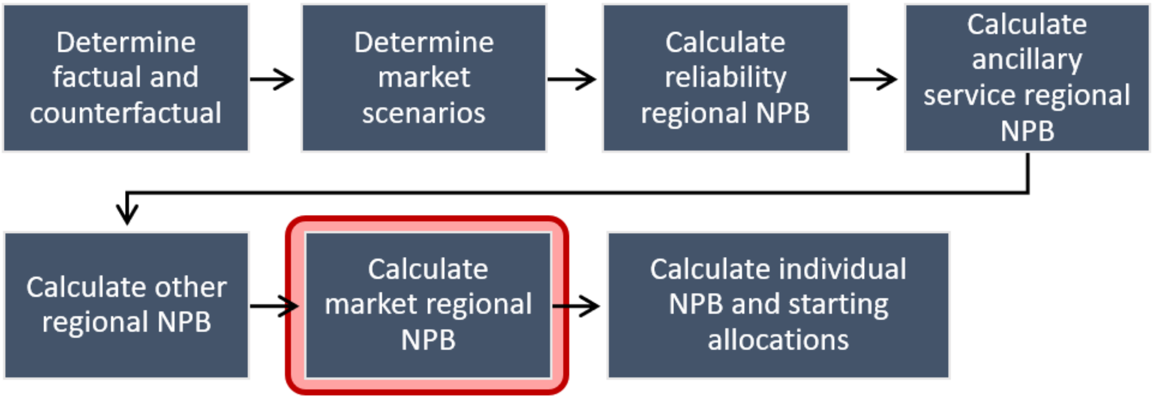
43. We do not expect the CNI BBI to have any material or measurable other benefits. Specifically, we do not expect any customer or embedded plant owner to receive benefits other than wholesale electricity market benefits from the CNI BBI.

44. Therefore, we did not calculate other regional NPB for the CNI BBI under clause 55.

8 Calculate market regional NPB

45. This section describes our application of the stages set out in section 3.3.6 of the assumptions book to the CNI BBI (and as shown in Figure 9).

Figure 9: Calculate market regional NPB



8.1 Determine if there are market benefits

46. We expect the CNI BBI to have a material impact on prices and/or dispatch quantities in the wholesale electricity market because it significantly alleviates constraints that would apply in the wholesale electricity market in the counterfactual. Therefore, in accordance with section 3.3.6.3 of the assumption book, we calculate market regional NPB as set out below.

8.2 Determine modelled constraints and investment grids

47. We followed the process in chapter 3, section 3.3.6.4 of the assumptions book to determine the modelled constraints for the CNI BBI.[15]

48. The modelled contingencies comprise the following circuits in the factual and counterfactual. Dispatch is constrained to ensure that other circuits in the CNI region do not overload following an outage of any one of the contingent circuits in the list below.

- BPE-BRK, BPE-TKU-1, BPE-TNG-1, BRK-SFD-1, HLY-SFD-1, HLY-TWH-1, RPO-TNG-1, RPO-WRK-1, SFD-TMN-1, TKU-WKM-2, TMN-TWH-1

15 We departed from the typical 20% threshold used to determine if contingencies should be included in the investment grid and instead used a 15% threshold. We did this to improve the accuracy of the process and therefore produce starting allocations that are broadly proportionate to EPNPB.

49. For the CNI BBI, we modelled transmission losses in SDDP on an hourly basis for the key CNI circuits[16] in the list below.

- BPE-TNG-1
- TKU-WKM-2
- BPE-MTR-1
- TKU-WKM-1
- SFD-TMN-1

50. Modelling AC losses internal to SDDP is a departure from the approach described in section 2.3.2.4 of the assumptions book. It is also a departure from the approach described in section 3.1.4 of Attachment D of the NZGP1.1 proposal, which describes how the investment test calculated losses in post-processing, rather than modelling them internally to SDDP.

51. We consider these departures necessary to calculate starting allocations that are broadly proportionate to EPNPB because:

- Alleviation of AC losses is a significant benefit of the CNI, as shown in Figure 16 of Attachment D of the NZGP1.1 proposal; and
- by modelling AC losses internally to SDDP, we can determine modelled regions based on the price separation caused by the losses.

52. We have only modelled losses on a small set of circuits in the CNI to minimise the impact of losses on system-wide supply-demand balance and reduce computational complexity. The key concern for determining modelled regions is the existence of price separation rather than the magnitude of the price separation. Periods where price separation occurs due to CNI losses – and the corresponding beneficiaries – can be identified by modelling losses on a small set of relevant circuits rather than all circuits in the system. Modelling losses on all circuits in the system would require us to adjust the load (which is "grossed up" to account for AC losses) and would significantly increase computational time. While there are other branches that have a reduction in losses as a result of the CNI BBI, losses on the circuits listed above (BPE-TNG-1, TKU-WKM-2, BPE-MTR-1, TKU-WKM-1, SFD-TMN-1, HLY-SFD-1) have the greatest reduction. Furthermore, because we are only modelling some AC branches with losses, we model a discrete set of parallel branches between the LNI and UNI included, but no more. If we included more branches, we would risk transmission flows becoming unbalanced through this interface in an unrealistic manner.

53. Therefore, the investment grids for the CNI BBI comprise:

- all existing branches and market nodes,
- a limit on HVDC transfer of 1200 MW (northward) in both the factual and counterfactual– i.e. assuming the HVDC Reactive Support BBI is commissioned independently of the CNI,
- the above modelled constraints in the counterfactual and alleviated in the factual, and
- some future AC circuit modifications (see section 8.3.3).

16 We consider losses to be modelled constraints for the purpose of the TPM, because they are a soft limit on transfer across the CNI circuits, which result in price separation either side of the circuit in a similar manner to a hard constraint.

8.3 Include other market model inputs

54. As noted above, chapter 2 of the assumptions book and the NZGP1.1 proposal contain most of the modelling inputs for the market scenarios we used for the CNI BBI. We used those modelling inputs.

55. We also used the following additional modelling inputs. These are either required by the TPM (in the case of the standard method calculation period and discounting of values to 2027) or chosen because we consider they will produce starting allocations that are broadly proportionate to EPNPB.

8.3.1 Standard method calculation period

56. The majority of the assets that make up the CNI BBI are expected to have useful lives of greater than 20 years. Therefore, we used a 20-year standard method calculation period (the maximum possible standard method calculation period), beginning on 1 January 2028 – the first 1 January after the CNI BBIs expected effective full commissioning date of 2027.[17]

57. We discounted all values to 2027. For the CNI BBI, 2027 is "year 0" in the present value calculation in clause 48(1) because the standard method calculation period starts in 2028.

8.3.2 Model resolution

58. We used SDDP with an hourly resolution rather than load blocks for consistency with the application of the investment test to NZGP1.1.[18]

8.3.3 AC circuit modifications

59. Table 1 shows modifications as a result of the CNI BBI, which only apply in the investment grid for the factual. In addition to these modifications, we included modifications to existing AC circuits that have been committed but not yet commissioned or are otherwise likely to occur in the near future. These modifications appear in the investment grids for both the factual and counterfactual; however, they do not affect the results of the modelling because they relate to circuits that are unaffected by the modelled constraints for the CNI BBI.

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17 See section 3.3.4 of Attachment D of the NZGP1.1 proposal.

18 We used load blocks for our previous benefits modelling due to then limitations on SDDP.

Table 1: AC circuit modifications used in CNI BBI

Name	From Bus	To Bus	Resistance (%)	Reactance (%)	Summer/ Winter/ Shoulder rating (MW)	Start Date
TKU-WKM-1	TKU220A	WKM220	0.58	4.44	823/864/844	1/6/2027
TKU-WKM-2	TKU220B	WKM220	0.58	4.41	823/864/844	1/6/2027
BPE-TKU-1	BPE220	TKU220A	3.00	14.45	399/429/418	1/12/2025
BPE-TKU-2	BPE220	TKU220B	2.99	14.36	399/429/418	1/12/2025
HLY-SFD-1	HLY220	SFD220	3.91	23.49	469/492/481	1/1/2024
ONG-RTO-1	ONG110	RTO110	NA	NA	open	1/1/2024

8.4 Run market model

60. We ran SDDP[19] using the input assumptions and market scenarios described in sections 4, 8.2 and 8.3. Because the network being modelled is different to that used for the application of the investment test to NZGP1.1, we re-ran SDDP to apply the TPM to the CNI BBI.

61. That is, by proposing to treat the CNI BBI as a separate BBI (see section 2.2), we are required to run SDDP using inputs for the CNI BBI specifically, whereas the investment test involved running SDDP using inputs for NZGP1.1 as a whole.[20] The differences in the SDDP modelling for the CNI BBI (i.e. running SDDP using inputs that relate to the CNI BBI specifically) are required to isolate those private benefits attributable to the CNI BBI rather than other BBIs that make up NZGP1.1.

8.5 Determine if clause 51 or 52 applies

62. The criteria for choosing between clauses 51 and 52, and the way in which we apply those criteria, are set out in section 3.3.6.7 of the assumptions book. Broadly, we are required to use clause 51 (the default method) to calculate market regional NPB unless certain conditions are met, as specified in clauses 51 and 52.

19 The market model used by Transpower. See [Software | PSR – Energy Consulting and Analytics (psr-inc.com)]

20 NZGP1.1 includes the HVDC Reactive Support, CNI and Wairakei investments.

63. The TPM broadly requires:

- the use of clause 51 if we determine that most of the market benefits of the BBI relate to new large generating plant (clause 51(1)(a)), or
- the use of clause 52 if clause 51(1)(a) does not apply and we determine that most of market benefits of the BBI are due to consumers avoiding high prices due to a lack of transmission and generation capacity during peak periods (clause 52(1)(b)(i)).

64. We have applied clause 51 for the CNI BBI.

65. We assessed whether clause 51(1)(a) applies to the CNI BBI by applying the test in paragraph 298 of the assumptions book (checking if most of the positive market regional NPB for the CNI BBI's regional supply groups relates to new large generating plant).

66. We determined it does not because the majority of positive market regional NPB for the CNI BBI's regional supply groups accrues to existing generating plant and customers rather than new large generating plant. South Island generators are expected to be beneficiaries of the CNI BBI, and our generation expansion model shows that generation capacity additions in the South Island are minimal (as shown in Figure 5), and will not exceed existing South Island generation capacity.

67. As clause 51(1)(a) does not apply, we are required to use clause 52 for the CNI BBI if either clause 52(1)(b)(i) or 52(1)(b)(ii) applies.

68. We assessed whether clause 52(1)(b)(i) applies to the CNI BBI by checking if most of the positive market regional NPB for the CNI BBI is derived from consumers avoiding having to pay their estimated cost of self-supply for electricity during peak demand periods, as required in paragraph 299 of the assumptions book. To determine whether this applies we divide:

- the present value of positive EMBD for regional customer demand groups during periods of deficit during the standard method calculation period; by
- the present value of positive EMBD for all regional customer groups over the standard method calculation period,

where EMBD is calculated according to clause 52. This method is a departure from paragraph 299 of the assumptions book in so far as periods of deficit may not exactly coincide with peak demand periods. However, we do not consider this lack of alignment affects the conclusion materially.

69. Since the total positive NPB from consumers avoiding having to pay their estimated cost of self-supply is less than 50% of total positive NPB (~4%) we are not required to use clause 52 by clause 52(1)(b)(i).

70. We assessed whether clause 52(1)(b)(ii) applies by considering whether using clause 51 will produce starting allocations that are broadly proportionate to EPNPB.

71. Having considered the matters in paragraphs 301 to 303 of the assumptions book, we have determined clause 51 does produce starting allocations that are broadly proportionate to EPNPB from the CNI BBI. This is because:

- the CNI circuits are part of the grid backbone i.e. not on the extremity of the grid, and
- our modelling clearly shows a reduction in price downstream of the modelled constraints between the factual and counterfactual, but – on average – shows a small reduction in price upstream, implying upstream generators would not benefit from the BBI. However, this BBI is likely to be particularly sensitive to input assumptions and the modelling framework used:
    - There are spring washer prices at Mataroa, Ohakune, National Park, and Ongarue in the counterfactual. Spring washer prices are notoriously sensitive to market conditions – or in a model – to its input assumptions.
    - Transmission losses can either result in prices being depressed upstream or rising downstream of the transmission circuit depending on if the marginal generator is upstream or downstream of the circuit in question. This means identifying the beneficiary of a reduction in losses relative to the counterfactual can be very sensitive to the precise location of the marginal generator. We do not consider it possible to forecast the marginal generator over 20 years with any precision. Therefore, the use of clause 52 could result in an arbitrary allocation between generation and load beneficiaries.
    - There is greater demand for generation in the counterfactual scenarios than the factual due to the higher losses. This increase in effective demand is not offset by an increase in generation build, because we used the generation scenarios from the application of the investment test which did not model losses internally (see section 8.2). As a result of using these generation scenarios with an SDDP run that has losses modelled internally, prices are artificially higher in the counterfactual scenarios everywhere in the grid, which is likely obscuring the price movements between the factual and counterfactual.

72. More generally, a reduction in transmission losses results in lower price separation between upstream generators and downstream loads. This results in a benefit to upstream generators irrespective of whether a reduction in losses results in prices falling downstream of the transmission circuit or rising upstream, as without this reduction in losses:

- Generation closer to the downstream consumer would be dispatched before generation upstream as it does not face the additional cost of transmitting its output to consumers.
- Similarly, in the long-run, transmission losses create a competitive disadvantage to upstream generation as new generation enters the market downstream to avoid the additional costs of transmitting via lossy circuits.

73. Therefore, the clause 51 method better reflects EPNPB for upstream generators than the clause 52 method.

8.6 Determine if clause 49(6) should be applied

74. For the CNI, we do not consider it necessary to adjust the prices from SDDP to moderate sensitivity. We used clause 51 to calculate market regional NPB, which is much less sensitive to modelled prices than clause 52, as the modelled prices are not used to calculate market regional NPB values (only to determine the potential modelled regions).

8.7 Determine potential modelled regions

75. As per paragraph 307 of the assumptions book, modelled regions are determined using the points of modelled constraint and the HVDC link constraints. We determined modelled regions by calculating correlation coefficients between prices in the counterfactual for one market scenario, in this case the Growth scenario. This resulted in the following modelled regions:

- South Island (**SI**)
- Lower North Island (**LNI**), all nodes in the North Island electrically south of and including BPE220, SFD220, BPE110 – including grid zone 6, grid zone 8, and grid zone 7[21] excluding MTR, OKN, NPK, TKU, TNG, RPO, TMN
- Upper North Island (**UNI**), all other nodes in the North Island

76. We consider these modelled regions meet the requirements of clause 50(1) for the CNI BBI, including being likely to produce starting allocations that are broadly proportionate to EPNPB.

8.8 Calculate PVEMBD for each customer at each connection location

8.8.1 Calculate EMBD for each market scenario – clause 51

77. We determined the CNI BBI's periods of benefit as the periods in which the price at Otahuhu is different to the price at Haywards in the counterfactual, which can only be because one or more of the CNI modelled constraints is binding, including due to the modelling of losses on certain circuits or because security constraints are binding (see section 8.2). As a result, most periods are periods of benefit because there is almost always price separation between Haywards and Otahuhu due to transmission losses.[22] This includes periods in which the price at Otahuhu is higher and lower than the price at Haywards, depending on the direction CNI constraints bind.

78. For South Island customers, the periods of benefit exclude periods in which the HVDC constraint is binding at the same time the CNI modelled constraints are binding, and power is flowing across the HVDC in the same direction as across the circuits affected by the CNI modelled constraints.

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21 A map of Transpower's grid zones can be found here: Grid Zone NZ Map.

22 We have excluded periods in which price separation is very small ($< 5\times10^{-5}$).

79. We then calculated expected market benefits or disbenefits (**EMBD**) and the present value of expected market benefits or disbenefits (**PVEMBD**) by customer and connection location before assigning the values to potential regional customer groups (section 8.10). We calculated EMBD by customer and connection location first because this is how SDDP produces the generation and load outputs used to calculate EMBD. This also allows for multiple regional supply or demand groups to be created in the same modelled region and for regional NPB attributable to future generation or load to be removed, as appropriate. This does not materially impact results and it facilitates, rather than detracts from, producing starting allocations proportionate to benefits.

80. The generation portion of EMBD for a customer at a connection location for each counterfactual outage was calculated using the following formulae from paragraph 319 of the assumptions book:

$$EMBD\_Gen\_nonUNI_{cust,loc} = \left(Gen_{cust,loc,CF,Nth} - Gen_{cust,loc,CF,Sth} + GenDelta_{cust,loc}\right)$$

$$EMBD\_Gen\_UNI_{cust,loc} = (Gen_{cust,loc,CF,Sth} - Gen_{cust,loc,CF,Nth} + GenDelta_{cust,loc})$$

where:

- $EMBD\_Gen\_nonUNI_{cust,loc}$ is the generation portion of EMBD for a non-UNI customer ($cust$) at a connection location (loc)
- $EMBD\_Gen\_UNI_{cust,loc}$ is the generation portion of EMBD for a UNI customer ($cust$) at a connection location (loc)
- $Gen_{cust,loc,CF,Sth}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when electricity is flowing south through the CNI (where prices are alleviated for non-UNI regional supply groups and are exacerbated for UNI regional supply groups) (Sth)
- $Gen_{cust,loc,CF,Nth}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when electricity is flowing north through the CNI (where prices are exacerbated for non-UNI regional supply groups and are alleviated for UNI regional supply groups) (Nth)
- $GenDelta_{cust,loc}$ is, for the customer ($cust$) at the connection location (loc), factual generation minus counterfactual generation.

81. The load portion of EMBD for a customer at a connection location was calculated using the following formulae from paragraph 320 of the assumptions book:

$$EMBD\_Load\_nonUNI_{cust,loc} = (Load_{cust,loc,CF,Sth} - Load_{cust,loc,CF,Nth} + LoadDelta_{cust,loc})$$

$$EMBD\_Load\_UNI_{cust,loc} = (Load_{cust,loc,CF,Nth} - Load_{cust,loc,CF,Sth} + LoadDelta_{cust,loc})$$

where:

- $EMBD\_Load\_nonUNI_{cust,loc}$ is the load portion of EMBD for a non-UNI customer ($cust$) at a connection location (loc)
- $EMBD\_Load\_UNI_{cust,loc}$ is the load portion of EMBD for a UNI customer ($cust$) at a connection location (loc)

- $Load_{cust,loc,CF,Sth}$ is the load supplied to the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when electricity is flowing south through the CNI (where prices are alleviated for non-UNI regional demand groups and are exacerbated for UNI regional demand groups) (Sth)
- $Load_{cust,loc,CF,Nth}$ is the load supplied to the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when electricity is flowing north through the CNI (where prices are exacerbated for non-UNI regional demand groups and are alleviated for UNI regional demand groups) (Nth)
- $LoadDelta_{cust,loc}$ is, for the customer ($cust$) at the connection location (loc), factual load minus counterfactual load.

8.8.2 Calculate present value EMBD

82. We calculated a market scenario-weighted EMBD by multiplying EMBD by the weighting for each market scenario, and also calculated EMBD as a present value in this step:[23]

$$PVEMBD = \frac{1}{\sum W_s} \sum_{s,t} \frac{EMBD_{t,s}}{(1 + discount\ rate)^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

8.8.3 Remove PVEMBD for customers or large plant that do not currently exist

83. We did not remove PVEMBD for large consuming plants that do not currently exist or any new load customers because we did not model any.

84. We removed PVEMBD for all new large generating plant that does not currently exist.

8.8.4 Split loads with more than one customer at a connection location

85. When there are multiple load customers at a connection location, load outputs from the market model were split into individual customers based on each customer's offtake at that connection location. For example, Bunnythorpe has two customers, Powerco and Kiwirail. Since the market model returns a combined load output for these two customers at Bunnythorpe, we split Bunnythorpe's load based on the two customers' intra-regional allocator (**IRA**) ratio. This step is necessary because a connection location may have two customers that are part of different regional customer groups e.g. a distribution customer and a non-distribution customer.

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23 As contemplated in clause 48(2). This effectively combines the calculations in clauses 48(1) and 51(6), and produces a mathematically equivalent result to doing those calculations separately.

86. When splitting load outputs where there are both distributor and non-distributor customers at a connection location, we assumed the load growth at the connection location is wholly assigned to the distributor customers. This is consistent with our demand forecasts for non-distributor customers, which generally assume no growth. The steps taken to do this are listed below using the Glenbrook (**GLN**) connection location as an example, which has two customers, Counties Energy (**COUP**) as a distributor customer and NZ Steel (**NZST**) as a non-distributor customer:

- Split load output for the first year (i.e. 2027 for the CNI BBI) based on the customers' IRAs. This resulted in 75% of GLN's first year load output assigned to NZST (~844 GWh) and 25% assigned to COUP (~301 GWh)
- Assume NZST's load at GLN remains the same at 844 GWh per annum throughout the standard method calculation period
- Calculate COUP's annual load at GLN by subtracting from GLN's total annual load 844 GWh (NZST's annual load for the first year). This resulted in an increasing load forecast for COUP, from 301 GWh in 2027 to 354 GWh in 2046
- Calculate a present value for the two customers' load forecasts using a 7% discount rate.[24] This resulted in 3,422 GWh for COUP and 8,937 GWh for NZST
- Calculate a present value load allocation based on the two load present values. This resulted in 28% for COUP and 72% for NZST

8.9 Determine potential regional customer groups

87. We set off generation disbenefits from load benefits (and vice versa) where a customer has injection and offtake at the same connection location, including where a distributor has embedded generation hosted in their network but we modelled it as a grid-connected generator under clause 49(5). We did this using the following formulae:

$$PVEMBD\_NetGen\_nonUNI_{cust,loc} = PVEMBD\_Gen\_nonUNI_{cust,loc} + PVEMBD\_Load\_nonUNI_{cust,loc} - (PVLoadDelta_{cust,loc} * 2)^{25}$$

$$PVEMBD\_NetGen\_UNI_{cust,loc} = PVEMBD\_Gen\_UNI_{cust,loc} + PVEMBD\_Load\_UNI_{cust,loc} - (PVLoadDelta_{cust,loc} * 2)$$

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24 We discounted the load forecast so that the allocation used to split the PVEMBD between the two customers is calculated on the same basis as the benefits to which it is applied.

25 The term $-(PVLoadDelta_{cust,loc} * 2)$ is used to make $PVGenDelta_{cust,loc} + PVLoadDelta_{cust,loc}$ mathematically equivalent to $PVGenDelta_{cust,loc} - PVLoadDelta_{cust,loc}$, which represents the change in net generation between the factual and counterfactual.

$$PVEMBD\_NetLoad\_nonUNI_{cust,loc} = PVEMBD\_Gen\_nonUNI_{cust,loc} + PVEMBD\_Load\_nonUNI_{cust,loc} - (PVGenDelta_{cust,loc} * 2)$$[26]

$$PVEMBD\_NetLoad\_UNI_{cust,loc} = PVEMBD\_Gen\_UNI_{cust,loc} + PVEMBD\_Load\_UNI_{cust,loc} - (PVGenDelta_{cust,loc} * 2)$$

where:

- $PVEMBD\_NetGen\_nonUNI_{cust,loc}$ is the present value of EMBD for a non-UNI customer ($cust$) at a connection location (loc) calculated based on net generation
- $PVEMBD\_NetGen\_UNI_{cust,loc}$ is the present value of EMBD for a UNI customer ($cust$) at a connection location (loc) calculated based on net generation
- $PVEMBD\_NetLoad\_nonUNI_{cust,loc}$ is the present value of EMBD for a non-UNI customer ($cust$) at a connection location (loc) calculated based on net load
- $PVEMBD\_NetLoad\_UNI_{cust,loc}$ is the present value of EMBD for a UNI customer ($cust$) at a connection location (loc) calculated based on net load.

88. We used the following potential regional supply groups (in each modelled region) to group customers at connection locations into potential regional supply groups for the CNI BBI.[27] A list of existing customers included in each regional supply group is available on our website as part of this consultation package.[28] Where there are multiple generation technologies owned by a customer at a connection location, we group based on the largest generation type.

- Wind Generation
- Controlled Hydro Generation
- Geothermal Generation
- Run-of-River Hydro Generation
- Thermal Commitment Generation
- Thermal Peaking Generation
- Battery Storage
- Cogeneration[29]

26 The term $-(PVGenDelta_{cust,loc} * 2)$ is used to make $PVGenDelta_{cust,loc} + PVLoadDelta_{cust,loc}$ mathematically equivalent to $PVLoadDelta_{cust,loc} - PVGenDelta_{cust,loc}$, which represents the change in net load between the factual and counterfactual.

27 We did not create the Biofuel or Solar potential regional supply group for existing customers discussed in section 3.3.6.11 of the assumptions book because, at the time of our previous benefits modelling, there were no grid-connected generating plants with these technologies. However, we created a solar and diesel (representing all thermal plant including biofuel) potential future regional customer group, as discussed in paragraph 93.

28 Starting BBI customer allocations | Transpower.

29 The Cogeneration group is a departure from paragraph 337 of the assumptions book. We consider this departure is necessary to produce starting allocations that are broadly proportionate to EPNPB as cogeneration is modelled as having a fixed production schedule rather than responding to market conditions like other thermal plant.

- Generation with Embedded Load (GenerationWithLoad) – connection locations with generation and significant load[30] owned by the same customer (or hosted by the same customer in the case of embedded load), excluding customers at a connection location with negative PVEMBD. The customer at the connection location is in this group if the customer's PVEMBD from the generation is greater than its PVEMBD from the load.

89. We grouped Alpine at Albury, Westpower at Kumara, and Aurora at Clyde into the South Island controlled hydro regional supply group despite these customer connection locations having negative PVEMBD. We did this because these customer connection locations have injection greater than their offtake during the capacity measurement period (**CMP**) for the CNI BBI, which indicates they have significant embedded generation, which we do not model in SDDP. If we did model this embedded generation, we expect these customer connection locations would be in South Island regional supply groups, and we consider grouping them as such would result in starting allocations that better reflect EPNPB. This is a departure from paragraph 335 of the assumptions book because we are taking into account information other than the SDDP outputs to group a customer at a connection location into a regional customer group.

90. We used the following potential regional demand groups (in each modelled region) to group customers at connection locations into potential regional demand groups for the CNI BBI. A list of existing customers included in each regional demand group is available on our website as part of this consultation package.[31]

- Industrial Load– load associated with industrial customers
- Non-industrial Load– load associated with non-industrial customers (primarily EDBs)
- Load with Embedded Generation– connection locations with load and significant generation[32] owned by the same customer (or hosted by the same customer in the case of embedded generation), excluding customers at a connection location with negative PVEMBD. The customer at the connection location is in this group if the customer's PVEMBD from the load is greater than its PVEMBD from the generation.

91. Due to the different magnitudes of market benefit that may accrue to these customer types from the CNI BBI, we considered it necessary to create these potential regional customer groups in each modelled region to produce starting allocations that are broadly proportionate to EPNPB.

92. We did not separate new and existing customers into separate regional customer groups because the benefits of the CNI BBI do not primarily accrue to new customers.

93. However, we created potential future regional customer groups for each of the following generation technologies that do not already exist in that modelled region. Without these potential future regional customer groups, customers with these types of new large plant would not have a regional customer group to join, and the BBI customer allocations after the new plant arrives would not be broadly proportionate to EPNPB.[33]

- UNI Solar Generation
- UNI Battery Generation

30 Specifically, where supply benefits are no less than 50% of demand benefits, or vice versa.

31 Starting BBI customer allocations | Transpower.

32 Specifically, where supply benefits are no less than 50% of demand benefits, or vice versa.

33 Unless they are later amalgamated with another group – see section 8.11.

- UNI Wind Generation
- LNI Solar Generation
- LNI Battery Generation
- SI Wind[34] Generation
- SI Solar Generation
- SI Battery Generation
- SI Thermal Generation

8.10 Calculate PVMRNPB for potential regional customer groups

94. We calculated the present value of market regional net private benefit (**PVMRNPB**) for each potential regional customer group as the sum of PVEMBD of all customers in that group. This was done using the following formulae:

$$PVMRNPB_S = \sum_{(cust,loc) \in S} PVEMBD\_NetGen_{cust,loc}$$

$$PVMRNPB_D = \sum_{(cust,loc) \in D} PVEMBD\_NetLoad_{cust,loc}$$

where:

- S is a set of all customers and connection locations belonging to potential regional supply group s
- D is a set of all customers and connection locations belonging to potential regional demand group d
- $PVMRNPB_S$ is PVMRNPB for potential regional supply group s
- $PVMRNPB_D$ is PVMRNPB for potential regional demand group d
- $PVEMBD\_NetGen_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location (loc) calculated based on net generation
- $PVEMBD\_NetLoad_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location (loc) calculated based on net load.

95. We removed potential regional customer groups with a PVMRNPB that was not positive (all UNI regional supply groups except UNI Thermal Peaking Generation, all LNI and SI regional demand groups, and SI Thermal Generation), which left the following potential regional customer groups:

- SI Controlled Hydro Generation

[34] While there were existing wind generating stations in the South Island at the time of our previous benefits modelling (Mahinerangi and White Hill), both were embedded so the owners are not beneficiaries of the CNI BBI in respect of those stations.

- SI Run-of-River Hydro Generation
- LNI Run-of-River Hydro Generation
- LNI Thermal Peaking Generation
- LNI Cogeneration
- LNI Wind Generation
- LNI Generation with Load
- UNI Non-industrial Load
- UNI Industrial Load
- SI Battery Generation (potential future regional customer group)
- LNI Solar Generation (potential future regional customer group)
- LNI Battery Generation (potential future regional customer group)
- SI Wind[35] Generation (potential future regional customer group)
- SI Solar Generation (potential future regional customer group)
- UNI Thermal Peaking Generation (potential future regional customer group)

96. We did not need to convert the quantity values of PVMRNPB to dollar values as we have not calculated regional NPB other than market regional NPB.

8.11 Finalise regional customer groups

97. We applied the process described in section 3.3.6.13 of the assumptions book to determine the final proposed regional customer groups.

8.11.1 Finalise regional supply groups

98. We have amalgamated some potential regional supply groups. As per paragraph 348 of the assumptions book, this amalgamation process requires the PVMRNPB/IRA ratio of an amalgamated group to be within 80% of the (larger) ratio of the other amalgamated group.[36].
    - The LNI Solar Generation ratio sits within 80% of the LNI Run-of-River Hydro Generation ratio, and so these groups are combined into a proposed regional supply group named LNI Run-of-River Hydro and Solar Generation.
    - The SI Wind Generation ratio sits within 80% of the SI Run-of-River Hydro Generation ratio, and so these groups are combined into a proposed regional supply group named SI Run-of-River Hydro and Wind Generation.

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35 While there were existing wind generating stations in the South Island at the time of our previous benefits modelling (Mahinerangi and White Hill), both are embedded so the owners are not beneficiaries of the CNI BBI in respect of those stations.

36 Amalgamation of potential regional customer groups is subject to the further conditions in paragraph 346 of the assumptions book.

- The SI Solar Generation ratio sits within 80% of the SI Controlled Hydro Generation ratio, and so these groups are combined into a proposed regional supply group named SI Controlled Hydro and Solar Generation.

99. The LNI Run-of-River Hydro Generation ratio is within 80% of the SI Controlled Generation ratio, as is the LNI Solar Generation ratio. However, in accordance with paragraph 346(c) of the assumptions book, we have not combined these groups as the difference in their benefits is due – at least in part – to constraints on the HVDC.

100. As a result, we finalised the following proposed regional supply groups for the CNI BBI:

- LNI Wind Generation
- LNI Cogeneration
- LNI Run-of-River Hydro and Solar Generation
- LNI Generation with Embedded Load
- LNI Peaking Generation
- LNI Battery Generation (future)
- SI Run-of-River Hydro and Wind Generation
- SI Controlled Hydro and Solar Generation
- SI Battery Generation (future)
- UNI Peaking Generation (future)

101. The PVMRNPB of each potential and proposed regional supply group is shown in Table 2.

Table 2: PVMRNPB of each potential and proposed regional supply group

Modelled region	Potential regional supply group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional supply group
Lower North Island	Wind Generation	24,597	2,155	11.4	9.13	Lower North Island Wind Generation
Lower North Island	Cogeneration	1,367	151	9.06	7.2	Lower North Island Cogeneration
South Island	Run-of-River Hydro Generation	372	41	9.0	7.2	South Island Run-of-River Hydro and Wind Generation
South Island	Wind Generation (future)	6	1	7.7	7.2	South Island Run-of-River Hydro and Wind Generation

Modelled region	Potential regional supply group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional supply group
South Island	Controlled Hydro Generation	122,491	17,708	6.9	5.5	South Island Controlled Hydro and Solar Generation
Lower North Island	Run-of-River Hydro Generation	691	104	6.6	5.3	Lower North Island Run-of-River Hydro and Solar Generation
Lower North Island	Solar Generation (future)	2	0.3	5.9	5.3	Lower North Island Run-of-River Hydro and Solar Generation
South Island	Solar Generation (future)	2	0.3	5.8	5.5	South Island Controlled Hydro and Solar Generation
Upper North Island	Peaking Generation (future)	0.04	0.008	4.9	3.9	Upper North Island Peaking Generation
Lower North Island	Battery Generation (future)	0.1	0.1	1.4	1.1	Lower North Island Battery Generation
Lower North Island	Generation with Embedded Load	535	1,194	0.4	0.4	Lower North Island Generation with Embedded Load
Lower North Island	Peaking Generation	123	554	0.2	0.2	Lower North Island Peaking Generation
South Island	Battery Generation (future)	0.003	0.1	0.04	0.0	South Island Battery Generation

8.11.2 Finalise regional demand groups

102. We have amalgamated the potential regional demand groups. As per paragraph 348 of the assumptions book, this amalgamation process requires the PVMRNPB/IRA ratio of an amalgamated group to be within 80% of the (larger) ratio of the other amalgamated group.[37] The UNI Industrial Load ratio sits within 80% of the UNI Non-industrial Load ratio, and so these groups are combined into a proposed regional demand group named UNI Load.

103. As a result, we finalised one proposed regional demand group – UNI Load.

104. PVMRNPB for each potential and proposed regional demand group is shown in Table 3, and the proportion of total PVMRNPB for each proposed regional customer group is in Table 4.

Table 3: PVMRNPB for each potential and proposed regional demand group

Modelled region	Potential regional demand group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional demand group
Upper North Island	Non-industrial Load	159,558	16,358	9.8	7.8	Upper North Island Load
Upper North Island	Industrial Load	10,140	1,068	9.5	7.6	Upper North Island Load

Table 4: PVMRNPB for proposed regional customer groups as a proportion of total PVMRNPB

Proposed regional customer group	PVMRNPB (GWh)	Percentage of PVMRNPB (excluding potential future regional customer groups)
Upper North Island Load	169,697	53.1%
South Island Controlled Hydro and Solar Generation	122,491	38.3%
Lower North Island Wind Generation	24,597	7.7%
Lower North Island Cogeneration	1,367	0.4%
Lower North Island Run-of-River Hydro and Solar Generation	691	0.2%
Lower North Island Generation with Embedded Load	535	0.2%

[37] Amalgamation of potential regional customer groups is subject to the further conditions in paragraph 346 of the assumptions book.

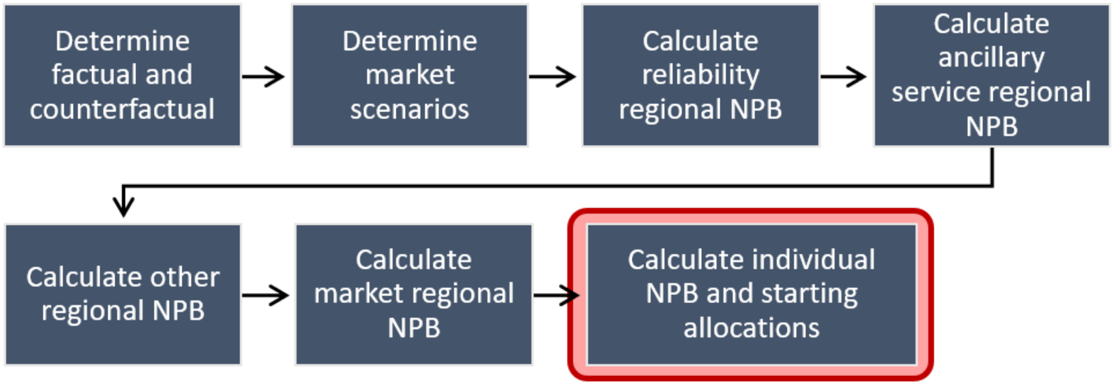
Proposed regional customer group	PVMRNPB (GWh)	Percentage of PVMRNPB (excluding potential future regional customer groups)
South Island Run-of-River Hydro and Wind Generation	372	0.1%
Lower North Island Peaking Generation	123	0.04%
Upper North Island Peaking Generation (future)[38]	n/a	n/a
South Island Battery Generation (future)	n/a	n/a
Lower North Island Battery Generation (future)	n/a	n/a

38 The proposed Upper North Island Peaking Generation, South Island Battery Generation, and Lower North Island Battery Generation regional supply groups are proposed future regional customer groups and so have no starting allocations.

9 Calculate individual NPB and starting BBI customer allocations

105. This section describes the stage highlighted in Figure 10 (and as set out in section 3.3.7 of the assumptions book).

Figure 10: Calculate individual NPB and starting allocations



9.1 Calculate IRA per customer per regional customer group

106. Proposed IRA values for the CNI BBI are calculated from historical data between 1 September 2018 and 31 August 2023 which are the five capacity years in CMP B for the CNI BBI.[39] The IRA values are available on our website as part of this consultation package.[40]

107. The CNI BBI is a non-peak BBI based on the amount of time the CNI BBI's modelled constraints are expected to bind during a counterfactual outage i.e. >90% as shown in Appendix A, Figure 13. If the benefits primarily accrued during peak periods, the modelled constraints would be binding much less frequently.

108. The IRAs for the CNI BBI are therefore mean historical annual offtake for regional demand groups and mean historical annual injection for regional supply groups. We calculated the IRA values in accordance with clauses 65(5) and 65(6), respectively, for most beneficiaries.

109. New customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRAs estimated, but, for recent customers, taking into account any available information about their offtake (clauses 66 and 83(3)(a)).

110. We have applied clauses 65(13) and 66 to estimate the IRA values for the following pre-start adjustment events that occurred during CMP B.

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39 We made a final investment decision for the CNI BBI in June 2024.

40 Starting BBI customer allocations | Transpower

Table 5: Pre-start adjustment events during CMP B

Customer	Location	Adjustment
TOPE	KOE	IRA values adjusted up to December 2020 due to Ngawha generation expansion using Te Mihi Geothermal as a comparator
NPOW	BRB	IRA values adjusted up to April 2022 due to refinery load disconnection and import terminal load connection using the refinery and import terminal data provided by Northpower
CHHE	KAW	IRA values adjusted up to May 2023 due to CHHE connection as new customer using KAW0112 transformed meter data and gross non-SKOG load provided by SKOG
WELE	TWH	IRA values adjusted up to June 2023 due to Te Rapa generation disconnection using Te Rapa embedded generation metered data
VECT	SVL	IRA values adjusted up to November 2022 due to CDC Data Centre load connection, based on offtake data provided by Vector.
VECT	HEN	IRA values adjusted up to November 2022 due to CDC Hobsonville Data Centre load connection and up to January 2023 due to Microsoft Data Centre load connection. These adjustments were calculated based on offtake data provided by Vector.
MERI	HRP	Harapaki wind farm connected June 2023. IRA value calculated based on an estimated injection of 542 GWh per annum provided by Meridian.
MSVP	LTN	Turitea wind farm connected in August 2020. IRA values estimated based on Tararua wind farm's IRA value, using relative plant capacity as a scaling factor.
WAV1	WVY	Waipipi wind farm connected in November 2020. IRA values estimated based on available metered data.

111. We are aware there are pre-start adjustment events that have occurred after the end of CMP B. We expect to process those as pre-start adjustment events under clause 75(4)(b).

9.2 Calculate individual NPB

112. We calculated each customer’s individual NPB for the CNI BBI as the sum of the present value of MRNPB for each regional customer group with positive PVMRNPB of which the customer is a member, multiplied by the customer’s IRA value for the group as a proportion of the total of all customers’ IRA values for the group.

9.3 Calculate starting allocations

113. We calculated each customer's proposed starting allocation for the CNI BBI as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the proposed starting allocations (to two decimal places) set out in Table 6. The unrounded proposed starting allocations are available in the Allocation worksheet of the post-processing model.

Table 6: Each customer's proposed starting allocation for the CNI BBI

Customer Name	Proposed starting allocation (%, 2 d.p.)
Vector Ltd	26.62%
Meridian Energy Ltd	26.57%
Contact Energy Ltd	8.55%
Powerco Ltd	7.64%
Unison Networks Ltd	4.07%
WEL Networks Ltd	3.69%
Northpower Ltd	2.46%
Genesis Energy Ltd	2.31%
Mercury SPV Ltd	1.99%
Counties Power Ltd	1.89%
MEL (West Wind) Ltd	1.78%
Waverly Wind Farm Ltd	1.57%
Tararua Wind Power	1.45%
New Zealand Steel Ltd	1.39%
Waipa Networks Ltd	1.30%
Manawa Energy Ltd	1.12%
Pan Pac Forest Product Ltd	1.06%

Customer Name	Proposed starting allocation (%, 2 d.p.)
Eastland Network Ltd	0.90%
MEL (Te Apiti) Ltd	0.90%
The Lines Company Ltd	0.76%
Winstone Pulp International	0.68%
Horizon Energy Distribution Ltd	0.46%
Whareroa Cogeneration Ltd	0.43%
KiwiRail Holdings Ltd	0.11%
Aurora Energy Ltd	0.11%
Westpower Ltd	0.08%
Nova Energy Ltd	0.05%
Alpine Energy Ltd	0.04%
Wellington Electricity Lines Ltd	0.01%
Southpark Utilities Ltd	0.00%[41]

114. To calculate BBCs for the CNI BBI, the starting allocations will be multiplied by the CNI BBI's covered cost. We have not included this step in this draft record as this step takes place after the calculation of starting allocations – which is the focus of this draft record.

115. A BBI's covered cost changes annually due to parameters including WACC and the attributed opex ratio and will not be certain until the BBI is fully commissioned. To assist stakeholders responding to consultation on this draft record, we present an estimate of covered cost and indicative BBCs for the CNI BBI in the consultation paper accompanying this draft record.

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41 Southpark Utilities has a starting allocation of 0.001% when rounded to 3 d.p.

Appendix A: Modelling detail

A1.1 Modelling Approach

A.1 This section describes the approach used in our analysis to model and calculate the benefits of the CNI BBI.

A.2 We use models of the New Zealand electricity system to calculate the benefits of the CNI BBI, by comparing the factual and counterfactual cases. We refer to the CNI BBI being fully commissioned as the factual. The counterfactual is the “do nothing” option of leaving the relevant CNI assets in their current state.

A.3 The key components of our analysis are:

- **Demand forecasting**. We have used variations of the market development scenarios produced by the Ministry of Business, Innovation and Employment (**MBIE**) in 2019. MBIE’s scenarios are called the Electricity Demand and Generation Scenarios (**EDGS**). We used all five of the 2019 EDGS scenarios (with variations) in order to cover the widest range of possible future demand growth. These scenarios are the Disruptive, Environmental, Global, Growth, and Reference scenarios.
- **Generation expansion planning**. We find a combination of new generation projects that would meet forecast demand while minimising system cost and considering firming requirements and hydrological uncertainty. For this analysis we use PSR Inc’s OptGen software. Aligning with the demand scenarios, unique generation expansion plans are developed for each 2019 EDGS scenario. The OptGen expansion plans for each 2019 EDGS scenario are modified to improve revenue adequacy of the generating plants, to better align with a realistic electricity market.
- **Generation dispatch simulations**. These simulations estimate electricity system operating costs for the counterfactual and factual cases. For this, we use PSR Inc’s SDDP software (v17.3.13) with generation dispatch simulations developed for each 2019 EDGS scenario.

A.4 Our modelling provides estimates of electricity system costs for the counterfactual and factual cases. The benefits of the factual are then calculated as the difference between the system costs of the factual and counterfactual cases.

A.5 For this analysis, we generally align with the modelling assumptions we used for our previous benefits modelling, which reflected the modelling assumptions in version 1.1 of the assumptions book. The primary exception is that, in 2023, we assumed that NZAS' aluminium smelter at Tiwai Point would close in 2024 or 2034. In May 2024, NZAS and Meridian announced they had negotiated a new electricity supply contract to 31 December 2044. We have therefore assumed for this analysis that the Tiwai smelter will remain open throughout the standard method calculation period,[42] greatly increasing South Island demand compared to our previous benefits modelling. We have not modelled any sensitivities for the smelter's closure.

A1.2 Demand Forecasting

A.6 The demand forecast used here aligns exactly with the demand forecast used in our previous benefits modelling (Tiwai closes 2024/34), with the single variation that the South Island demand continuously grows instead of dropping precipitously in the year of NZAS closing. Figure 11 shows a comparison between the North and South Island demand forecasts used for the current modelling (Tiwai remains open) and the previously consulted on modelling that assumed Tiwai closes in 2024.

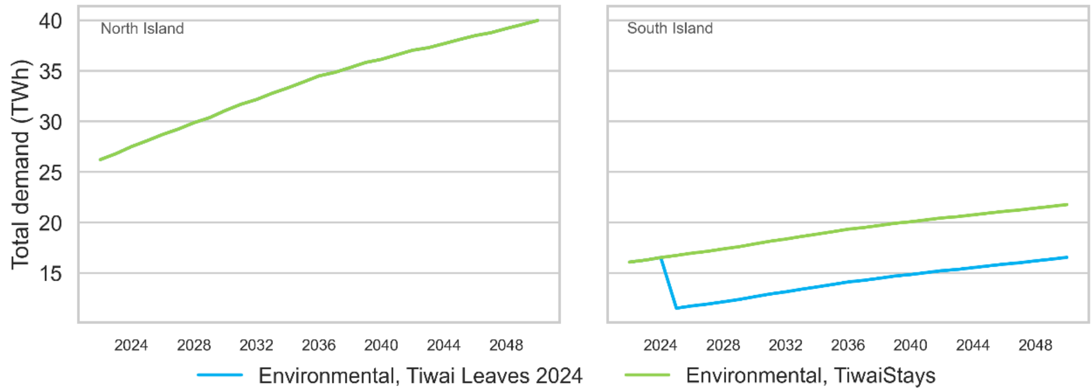

Figure 11: Demand forecast comparison between Tiwai leaves (2024) and Tiwai stays modelling (Environmental scenario)

A1.3 Generation Expansion Planning

A.7 Generation expansion planning is the process of forecasting future grid connected generation for a given demand forecast. Generation expansion plans are an input to our generation dispatch simulations.

42 Although the current electricity supply contract expires in December 2044, for simplicity we have assumed it will be renewed, or replaced with a new contract, for the remainder of the standard method calculation period (i.e. until at least the end of December 2047). We note that benefits accruing at the end of the standard method calculation period have a relatively small impact on EPNPB due to discounting.

A.8 Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (to the end of 2047), adding new generation as required to meet forecast demand while minimising system cost. We recognise that there are other factors that play a role in generation investment decisions such as the availability of capital, future views on wholesale electricity prices, the ability of the project to gain consents, power purchase agreements, and retail positions relative to generation. However, our view is that it is reasonable to focus on generation costs on the basis that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, cost will be the major deciding factor.

A.9 PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use PSR's 'Optgen2' algorithm. Optgen2 finds a least-cost plan by co-optimising build decisions and hourly operation in one optimisation. It represents wind/solar ups and downs with typical days and seasons and uses firm capacity constraints.

A.10 We constrain the model in the first two to three years (market scenario dependent) to build generation projects to which developers have committed, or that are in the advanced stages of Transpower's connection pipeline. For the remainder of the standard method calculation period, the model is allowed to build from a wider generation stack of specific known projects at earlier stages of development and generic projects where the resource is known to exist, but a project has not been publicly announced.

A.11 As an additional step, the generation expansion plans from OptGen are adjusted to improve the modelled revenue adequacy of future generation projects. Revenue adequacy is the ratio of expected revenues over expected capital costs. While it can be difficult to model revenue adequacy, particularly in a future dominated by intermittent renewable generation, future generation plants should in general be revenue adequate.

A.12 These adjustments are made as a 'post-processing' step, after the OptGen modelling process. The existing and committed generation is left untouched, but future generation is shifted in time through an iterative process with the goal of achieving plant revenue adequacy over a 10-year period. Adjustments are done in such a way as to introduce no significant difference between North Island and South Island average short run marginal costs (**SRMCs**), while still ensuring revenue adequacy remains within reasonable modelling tolerances.

A.13 We produced generation expansion plans for each of the five 2019 EDGS scenarios. We applied the same generation expansion plan to the counterfactual and factual cases for each 2019 EDGS scenario. We assumed that the AC grid is unconstrained (i.e., that future generation development would be unaffected by circuit constraints on the key CNI transmission lines). We note that these are the same generation expansion plans used in the HVDC Reactive Support BBI factual case modelling, which upgrades the HVDC link capacities in 2026 (1200 MW north, 850 MW south).

A.14 All changes to generation capacity from 2022 to 2047 are summarised (cumulatively) in Figure 4 and Figure 5 for the North and South Island, respectively.

A1.4 Generation Dispatch Simulation

A.15 SDDP is a well-established dispatch model that is widely used internationally. SDDP minimises the electricity system operating costs, accounting for:

- future changes in generation and grid scale batteries – as provided by our generation expansion plans
- future changes to the transmission network for each investment option and the counterfactual

- changes in demand – arising from daily and weekly demand variations through to long term forecast demand growth
- hydro inflow variability and uncertainty
- renewable energy variability
- grid scale battery operation, and
- plant operational constraints - including thermal plant unit commitment and hydro plant minimum flow constraints.

A.16 SDDP generation dispatch simulations are produced in two steps:

- **Policy evaluation**: In this step SDDP derives a policy, effectively a set of water value functions considering all of New Zealand's major hydro reservoirs. Water value functions provide the weekly opportunity cost of using or storing water in each hydro reservoir as a function of lake levels, accounting for risks of both dry year energy shortages and wet year hydro spillage.
- **Simulation**: Using water value function from the policy evaluation, the operation of the electricity system is simulated for a set of 50 unique hydro inflow sequences.

A.17 SDDP policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water values. For this analysis, consistent with our generation expansion plan approach, we ran policies for each of the five 2019 EDGS scenarios. For a given 2019 EDGS scenario, we applied the same policy to the counterfactual and factual cases, on the basis that upgrades to the CNI grid are unlikely to substantively alter water values for major hydro generation schemes.

A.18 For this analysis, we use an hourly resolution over the standard method calculation period to 2047 for generation dispatch simulations. The hourly resolution allows us to capture real world variations in demand and renewable generation, at the cost of increased model solve time and storage requirements. This is an enhancement on the modelling undertaken in 2023, which is now feasible due to improvements in SDDP.

A.19 SDDP models the optimal dispatch of generation and battery resources across the electricity system using a set of yearly hydro inflow sequences that represent conditions for all modelled hydro generators. In New Zealand, electricity system costs vary significantly with hydro inflows, so capturing this behaviour is a critical part of our generation dispatch simulations.

A.20 We use 'synthetic' hydro inflow sequences that are derived from historical hydro inflow records. Synthetic inflows reduce the level of fluctuations, help the model converge, and reduce model solve time. They are produced by SDDP by analysing the relationship between an inflow sequence and time of year, as well as the interdependence among inflows to different hydro catchments.

A.21 For this analysis, we used:

- **For the policy evaluation step:** 15 and 50 synthetic inflow sequences, respectively, for the 'backward' and 'forward' phases of the SDDP algorithm.
- **For the simulation step:** 50 synthetic inflow sequences.

A.22 SDDP uses a simplified, linear, DC load flow model. For this analysis, we introduced the following additional simplifications to our modelling approach:

- Circuit upgrades/changes in the factual case are given in Section 8.3.3. In addition to these modifications, we include modifications to existing AC circuits that have been committed but not yet commissioned or are otherwise likely to occur soon. These "existing" circuit modifications appear in the investment grids for both the factual and counterfactual cases; however, they do not affect the results of the modelling because they relate to circuits that are unaffected by the modelled constraints for the CNI BBI.
- Circuit flows are constrained to respect both thermal ratings and other system constraints only for the key CNI circuits listed below. The rest of the AC grid is modelled as unconstrained.
- AC network losses are included in the SDDP generation dispatch simulation for the key CNI circuits listed below. AC losses are ignored for all other AC circuits.
- The following circuit contingencies are modelled in the factual and counterfactual cases: BPE-BRK-1, BPE-TKU-1, BPE-TNG-1, BRK-SFD-1, HLY-SFD-1, HLY-TWH-1, RPO-TNG-1, RPO-WRK-1, SFD-TMN-1, TKU-WKM-2, TMN-TWH-1
- Losses on the HVDC link are modelled within SDDP using a linearised approximation of observed HVDC losses.

A.23 The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plans and generation dispatch simulations. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network. To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing tranches as described in Table 7. Each tranche is for a given amount of deficit, expressed as a percentage of hourly island demand. The first three tranches are intended to represent voluntary demand response measures, such as retailers controlling hot water cylinder demand. The last high value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency.

Table 7: Generation expansion plan modelling deficit cost tranches

Deficit as a proportion of Island hourly demand	Cost (2021$)
First 5% of demand	$600 per MWh
Between 5% and 10% of demand	$800 per MWh
Between 10% and 15% of demand	$2,000 per MWh
Greater than 15% of demand	$10,000 per MWh

A.24 Many other model inputs are not explicitly listed here and are consistent with the modelling assumptions we used to calculate starting allocations for the CNI BBI in 2023, which reflect those in chapter 2 of the assumptions book.[43]

43 TPM Determination: BBC Assumptions Book v1.1, 16 March 2023.

A1.5 Generation Dispatch Simulation Results

A.25 This Section provides an overview generation dispatch simulation results that directly relate to the calculation of the CNI BBI's starting allocations. The benefits and disbenefits differ per 2019 EDGS scenario as customers' exposure to the loss reductions and security constraints across the CNI differ per 2019 EDGS scenario. We defined the periods of benefit to be periods when there is price separation between nodes OTA220 and HAY220. We note that this price separation will arise due to losses (through key circuits) as well as binding flow constraints; however, as the two add in the same direction, it is unnecessary to disentangle the two effects.

A.26 Losses are reduced by splitting the 110 kV network at Ongarue (part of the CNI BBI), because energy that is presently transported on the 110 kV network will be redirected thought the less lossy 220 kV network. Security constraints are relieved by capacity increases on the TKU-WKM 1 and 2, BPE-TKU 1 and 2, and HLY-SFD-1 circuits. In addition to relieving security constraints, the TKU-WKM 1 and 2 duplexing (part of the CNI BBI) also reduces losses on the circuits, further increasing the loss benefit of the split on the 110 kV network at Ongarue.

A.27 In the graphs below, we refer to any period with a higher price at OTA220 than HAY220 as "north" and any period with a higher price at HAY220 than OTA220 as "south".[44] By way of illustration:

- Figure 12 and Figure 13 show the frequency of price separation between HAY220 and OTA220 in the Environmental scenario factual and counterfactual cases. Clearly, losses and binding constraints are reduced in the factual case, for both north and south flows.
- Figure 14 shows the loss costs for the Environmental scenario in 2045 in the factual and counterfactual cases, demonstrating the significant cost benefit from the CNI BBI.

A.28 Note that these graphs include data averaged across all hydro scenarios, and although results for a single 2019 EDGS scenario are shown, the trends hold for all five 2019 EDGS scenarios.

[44] Due to losses, there will always be a price separation between the two buses, so we apply a threshold of 0.0025*SRMC for counting a period of price separation.

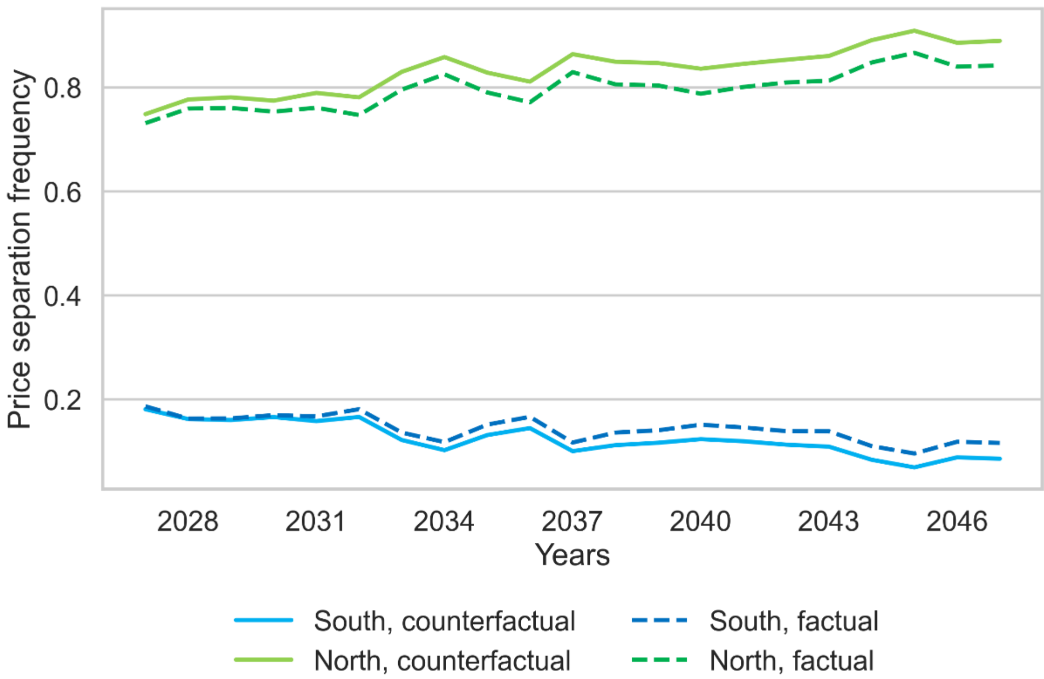

Figure 12: Frequency of price separation (OTA220 vs. HAY220) for the Environmental factual and counterfactual cases

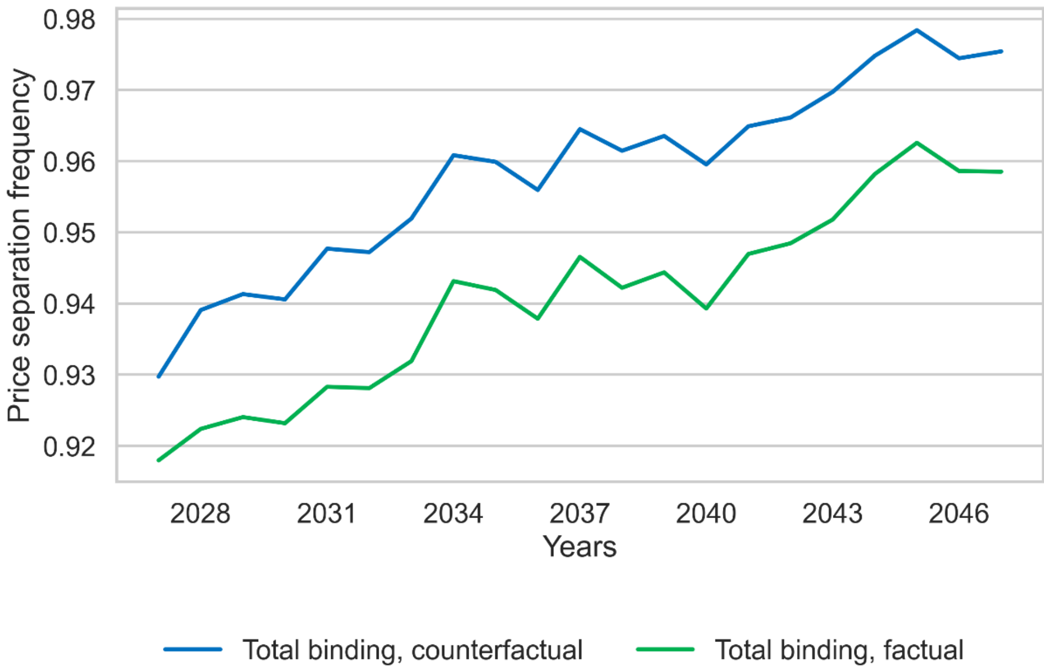

Figure 13: Total frequency of price separation (OTA220 vs. HAY220) for the Environmental factual and counterfactual cases

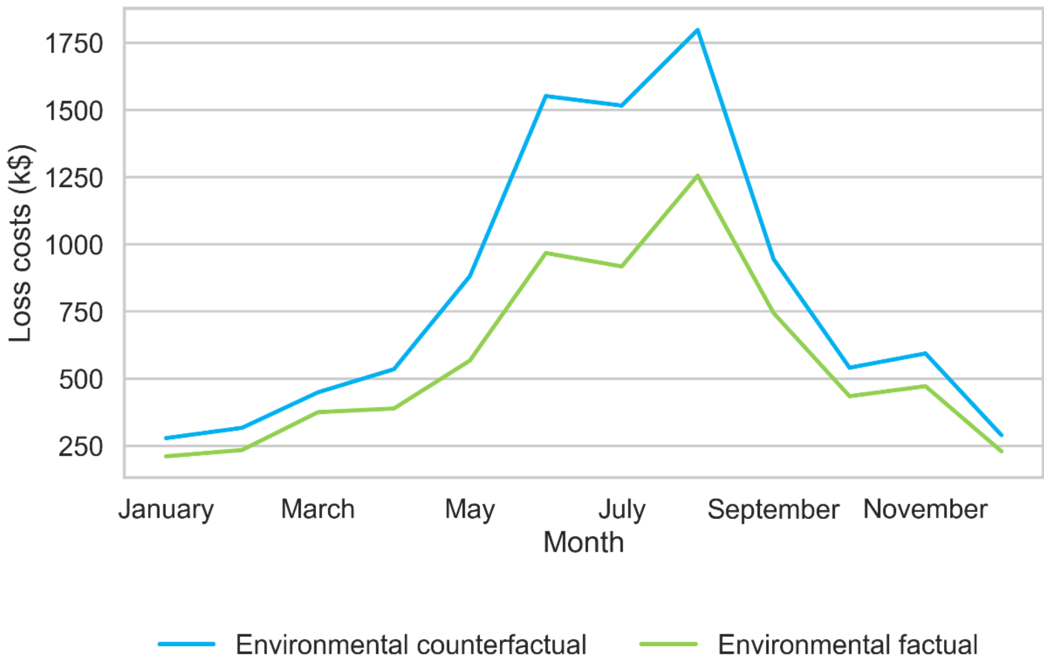

Figure 14: Circuit loss costs in 2045 for the Environmental factual and counterfactual cases

A.29 Figure 15 shows the total yearly deficit averaged over all hydro scenarios for the Environmental scenario. The difference between the factual and counterfactual deficit costs is minimal throughout the standard method calculation period, so deficit avoidance is not a significant benefit of the CNI BBI.

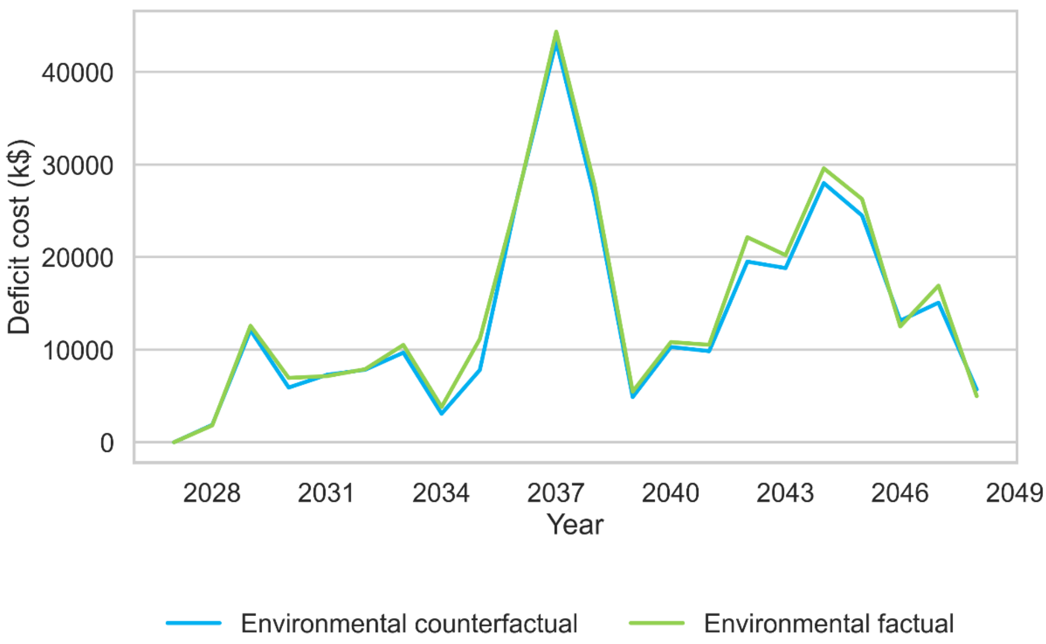

Figure 15: Deficit costs for the Environmental factual and counterfactual cases

Appendix B: Glossary

Term	Meaning
AC	Alternating Current
Authority	Electricity Authority
BBI consultation documents	The documents produced to support the consultation on the proposed starting allocations for each high-value post-2019 BBI
Capex	Capital expenditure
Cascade failure	The successive failure of transmission or generation components leading to widespread failure of the power system over a large area
CMP	Capacity measurement period
Code	Electricity Industry Participation Code 2010
Constraint	A local limitation in the transmission capacity of the grid required to maintain grid security or power quality
Contingency	An unplanned event in the power system, including loss of a transmission asset
CUWLP	Clutha-Upper Waitaki Lines Project
Deficit	Unsupplied electricity demand due to a lack of transmission and/or generation capacity
EDGS	Electricity Demand and Generation Scenarios – see Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz)
EMBD	Expected market benefit or disbenefit
EPNPB	Expected positive net private benefits

Term	Meaning
HVDC link	High voltage direct current inter-island link, the transmission link between the North and South Islands
IM	Input Methodology
IRA	Intra-regional allocator
Investment test	The investment approval test under section III of Part F of the Electricity Governance Rules 2003 (now revoked) or the Transpower Capex IM
kVAr	KiloVolt Ampere reactive (reactive power)
kWh	KiloWatt hour (energy)
MBIE	Ministry of Business, Innovation & Employment
MW	MegaWatt (power)
MWh	MegaWatt hour (energy)
NPB	Net private benefit
Opex	Operating expenditure
OptGen	The generation expansion tool used by Transpower. See PSR | OptGen — Model for generation expansion planning and regional interconnections (psr-inc.com)
Pre-contingent load management	Load management that results from the application of a pre-contingent market constraint.
Pre-contingent market constraint	A security constraint applied by the system operator in the wholesale electricity market, usually limiting transmission flow over one or more circuits, affecting the dispatch and prices.
PVEMBD	Present value of expected market benefit or disbenefit
PVMRNPB	Present value of market regional net private benefit

Term	Meaning
SDDP	The market model used by Transpower. See Software | PSR – Energy Consulting and Analytics (psr-inc.com)
SPD	The scheduling, pricing, and dispatch tool used by the system operator for dispatching generators, creating prices, and forecasting dispatch and prices
SPS	Special protection scheme
System condition	The load and generation patterns Transpower uses to highlight transmission issues we can reasonably expect to occur with currently available information and trends. See Transmission Planning Report 2021.pdf (transpower.co.nz)
TPM	Transmission pricing methodology
Transmission alternative	A service provided by a third party to Transpower to defer or avoid investment in the grid – e.g. demand response
TWAP	Time weighted average price
VoLG	Value of lost generation
VoLL	Value of lost load

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